BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	)	DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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I. INTRODUCTION

Q. Please state your name and business address, and identify your employer.

A. My name is Douglas C. Smith. I am the Technical Director for La Capra Associates, 20 Winthrop Square, Boston, Massachusetts.

LaCapra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For over twenty years, we have served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Staff of the Arizona Corporation Commission ("Staff").

Q. Please summarize your professional background and education.

A. I am an electric power industry planning and transactions specialist with 17 years of experience in areas including power systems planning and analysis, wholesale and retail power transactions, and electric utility rates. I have participated in restructuring-related activities in Pennsylvania, Massachusetts, Vermont, New Jersey and Ohio. I have participated in numerous generation asset valuation and competitive market assessment projects on behalf of merchant generating companies, electric utilities, state regulatory and consumer agencies, and end-users. During the past two years I have assisted the California Bureau of State Audits in its review of approximately $50 billion of transactions conducted by the California Department of Water Resources ("DWR") in 2000 and 2001, and I have reviewed the power transactions of PacifiCorp (which serves six states in the western United States) and the Arizona Electric Division of Citizens Communications Company.

I have managed the electric power supplies of several electric utilities, and have advised electric utilities regarding their power transactions and risk management strategies. I presently assist several retail electricity customers, including the National Railroad Passenger Corporation ("Amtrak"), in the procurement of retail generation service from competitive suppliers. I have presented testimony before state regulatory authorities in Pennsylvania, Massachusetts, New Hampshire, New Jersey, Vermont, Wyoming, Arizona, Nevada and Puerto Rico.

A copy of my resume is included as Exhibit DCS-1.

I. SUMMARY

Q. Please summarize your testimony.

A. I have reviewed the Company's proforma Test Year fuel and purchased power expenses, particularly as presented by APS witness Donald Robinson. On the basis of my review, I recommend several changes to the Adjusted Test Year fuel and purchased power expenses submitted by APS. I also discuss the merits and drawbacks associated with potential purchased power and fuel adjustment mechanisms, and recommend that the Commission not approve an adjustor for APS in this proceeding.

Q. Please summarize your findings with regard to fuel and purchased power expenses.

A. I recommend changes to the Company's pro-forma analysis of fuel and purchased power expenses, based on two issues: transportation costs for owned and purchased gas-fired resources; and the assumed availability of the Palo Verde generating units. I have developed an adjustment to the Company's pro forma purchased power and fuel costs to reflect these two issues.

As explained by Staff witnesses Linda Jaress and Harvey Salgo, Staff does not support APS' proposal to rate base the PWEC generating units. The amount of my recommended adjustment regarding natural gas transportation costs depends to a significant extent on whether or not the PWEC units are part of the

Company's power supply mix. Therefore, the effects of my proposed adjustments to the Company's pro forma fuel and purchased power analysis are as follows:

- ? A $5.08 million reduction (for both PWEC in and out) to reflect higher availability for the Palo Verde generating units. The jurisdictional component of this adjustment is $5.0 million;
- ? A $4.61 million reduction to reflect lower gas transportation costs (if the PWEC units are included in rate base), or a $1.48 million reduction if the PWEC units are not included in rate base. The jurisdictional components are $4.54 million and $1.46 million respectively.

I have provided these recommended adjustments to Staff witness James Dittmer, for incorporation in his analysis of the Company's total cost of service. These modifications to the Company's proposed revenue requirement provide an appropriate base from which to develop a fuel and purchased power adjustor, as they represent an updated view of fuel and purchased power costs. My fuel and purchased power recommendation, however, should be reduced by approximately $23 million if the Commission concludes that APS should not have an adjustor.

Q. Please summarize your findings and recommendations with respect to a prospective power supply adjustor mechanism.

A. The Commission's Decision No. 66567 in Docket E-01345A-02-0403 contemplates an adjustor that would address only changes in the Company's purchased power costs. Staff is concerned that an adjustor that addresses only purchased power expenses would not accurately depict changes in the Company's net power supply costs, including fuel expenses and revenues associated with sales for resale. In APS' present circumstances, this flaw is important because fuel expenses, purchased power expenses, and sales for resale revenues each can have a significant effect on the net power costs. An adjustor addressing only purchased power would also fail to provide incentives for APS to operate its system in a least-cost manner, and could actually encourage APS to make power supply choices that increase its net power supply costs.

For these reasons, Staff recommends that the Commission not implement an adjustor mechanism that focuses solely on purchased power expenses. The preferable options range from no adjustor at all (i.e., a fixed retail rate) to a "full" adjustor designed to reconcile all changes in APS' fuel costs, purchased power costs, and resales.

Staff is concerned, however, that in the event of significant load growth an adjustor could lead to an unintended overrecovery of APS' total power supply costs. This is meaningful for APS because: (a) it has experienced significant load growth in the past, and expects to continue to do so; and (b) APS has relatively large fixed power costs, which would tend to decline on a cents/kWh basis as load grows but would not be included in an adjustor as presently envisioned. Staff's view is therefore that the adjustor currently proposed by APS would not be appropriate. If the concern with respect to potential overrecovery can be adequately addressed, Staff would support an adjustor that includes purchased power and fuel costs.

II. FUEL AND PURCHASED POWER COSTS

Q. Please provide an overview of the Company's power supply sources.

A. In developing its pro forma fuel and purchased power costs, APS conducted an analysis using the Real Time Simulation ("RTSIM") production simulation software. This analysis is intended to approximate the dispatch of the APS system on a daily and hourly basis, taking into account the APS load shape and the characteristics of its owned generating plants and its committed purchase and sale transactions. The analysis also estimates the effects of short-term exchanges (e.g., daily and hourly purchases and sales for resale) with the regional wholesale electricity market.

I have summarized the results of APS' simulation analysis as follows. Exhibit DCS-2 shows APS' monthly energy mix, in terms of the major types of power plant and interchange, assuming that the PWEC units are included in ratebase.

Exhibit DCS-2 also presents the same summary, assuming that the PWEC units are not included in ratebase. Exhibit DCS-3 summarizes APS' annual energy mix, along with the average price of fuel (or purchases/sales, as applicable) for each category, for the PWEC "in" and "out" cases.

From the perspective of assessing APS' exposure to fuel and market price changes, the following observations are notable:

? Most of the APS energy supply comes from its nuclear units (with an average fuel cost of roughly $5 per MWh) and coal-fired units (with an average fuel cost of less than $13/MWh). From a system operations perspective, these units are almost always fully utilized to meet APS' present retail load requirements, with very little surplus available for resale.

? A substantial portion of the APS energy supply comes from gas-fired generating units – a combination of APS-owned units and the PWEC units. These gas-fired units tend to be the Company's marginal generating sources, following its seasonal and daily load requirements. The average fuel costs for the gas-fired units are much higher than for the Company's coal and nuclear units, and well above the system average cost per MWh for fuel and purchased power. As shown on Exhibit DCS-3, the gas-fired units are estimated to provide about 25% of total system energy requirements (assuming PWEC is ratebased) but represent a cost of about $299 million per year or over half of the Company's net fuel and purchased power cost. As a result, changes in natural gas prices can significantly affect the Company's total fuel and purchased power expense. Similarly, changes in the operation of the gas-fired units (e.g., due to demand growth, or unseasonably hot or cool weather) can have a significant effect on APS' total fuel expense.

? If the PWEC units are not included in rate base, APS will be a modest net purchaser in the spot market. Specifically, the net of daily and hourly transactions amounts to a net purchase of roughly 1 million MWh or about 4 percent of the APS system requirements. The APS analysis shows that if the PWEC units are included in rate base, APS will be a net seller in the spot market. Estimated net spot market sales amount to about 1.7 million MWh per year, or roughly 6.5 percent of APS system requirements.

In summary, the APS fuel mix has a significant amount of fuel diversity, but energy supplied by gas-fired generating units and purchased from the spot market represent a substantial portion of APS' net power supply costs.

Q. How does APS' significant reliance on natural gas-fired generation and market power purchases affect its future rate path?

A. Natural gas prices have shown considerable variance in recent years, as illustrated on Exhibit DCS-4.[1] As the Commission knows, electricity markets also tend to feature volatile prices, driven in part by natural gas prices as well as numerous other factors.

It is reasonable to expect that both gas and electricity market prices will continue to vary significantly in the foreseeable future. The Company's gas fuel costs and electricity market purchases, if not hedged, will represent a significant source of cost uncertainty in future years. Even if APS does conduct an aggressive hedging program, it will probably not be practical to eliminate all fuel cost uncertainty. Whether or not the PWEC units are included in rate base, it appears that APS' natural gas fuel requirements will represent a larger net expenditure in the near term (and, likely, a larger financial risk exposure) than the Company's projected spot market electricity transactions.

Q. Are increases in fuel prices a primary driver of APS' requested rate increase?

A. Yes. Recent spot prices for natural gas, and forward indicators for natural gas deliveries in 2004, are well above actual gas price levels that were experienced in the Test Year. The natural gas price environment also affects electricity market prices. Electricity forward prices for deliveries in 2004 have increased relative to Test Year spot market prices, as well. As I will explain below, APS' pro forma power cost analysis reflects this higher price environment.

These gas and market price increases are significant in the context of the APS power supply, even though APS gets most of its energy from nuclear and coal-fired units that feature lower and more stable fuel prices. In addition to a significant amount of owned natural gas-fired generation, APS has in place large

[1] Staff witness Barbara Keene submitted this same exhibit in Docket E-01345A-02-0403.

gas-fired purchases (i.e., Track B purchases from the PWEC units) during summer months. APS also makes short-term market purchases at prices that reflect, in part, marginal gas-fired units in the WECC region. If the PWEC units are ratebased, APS power supply costs will depend even more directly on natural gas prices. The increases in natural gas and (to a lesser extent) electricity market prices are the primary driver of APS' pro forma increase to fuel and purchased power costs.

Q. What natural gas and electricity market price assumptions did APS utilize as inputs to its pro forma analysis in this case?

A. In developing its pro forma adjustment to fuel and purchased power costs, APS relied on monthly market price quotations that were available in late April 2003, for gas and electricity deliveries in the following twelve months (May 2003 through April 2004). The forward gas prices were at key supply basins; APS added applicable variable transportation costs, losses and taxes to obtain effective delivered prices to its generating plants. The forward electricity price quotations were for monthly peak and off-peak deliveries at Palo Verde, a western trading hub close to the APS service territory. In its production simulation analysis, APS utilized the monthly Palo Verde forwards to develop prices for daily and hourly spot market purchases.

APS made one broad adjustment to those forward prices: a reduction of ten percent to the natural gas prices. APS explained this adjustment as compensating for what it believed were exceptionally low forward spark spreads (i.e., the difference between forward electricity and natural gas prices) being quoted in the market.

Q. How do the Company's price assumptions for natural gas and electricity compare to recent conditions?

A. Short-term market prices for gas and electricity have fluctuated noticeably between April 2003 and the present. Recent forward price quotations provided by the Company, however, indicate that the natural gas and electricity market prices underlying the Company's pro forma analysis are reasonably representative of current market expectations for deliveries in the near future - including the period July 2004 to June 2005, the first year in which the rates set in this docket will be in effect. It therefore appears that the Company's assumptions about the natural gas and electricity price environment are suitable for use in setting the reference level of fuel and purchased power costs in this case, particularly if a PPFAC is adopted.

III. NORMALIZATION OF FUEL & PURCHASED POWER

Q. In developing its adjustment to fuel and power costs, did APS consider load growth beyond the test year?

A. Yes. The Company's pro forma adjustment to fuel and purchased power costs, which is summarized in Mr. Robinson's Attachment DGR-5, page 7, relies in part on assumed load growth in 2003.

Q. Please explain what sales levels were used to develop the normalized fuel and purchased power costs.

A. First, APS estimated a normalized 2003 fuel and purchased power cost of 2.317 cents/kWh. This figure represents estimated normalized 2003 fuel and purchased power costs of $584.087 million, divided by normalized 2003 sales of about 25.2 million MWh. This sales level is associated with projected year-end 2003 customer levels, and is well above the Company's actual test year sales.

Next, APS compared the normalized 2003 fuel and purchased power cost of 2.317 cents/kWh to the test year fuel and purchased power cost of 1.8033 cents/kWh, determining that power costs per kWh will be higher by 0.5137 cents/kWh than average 2002 power costs. The increase is due both to higher fuel and purchased power costs and to a different dispatch of generating units to meet higher load.

Finally, APS multiplies this adjustment to its adjusted 2002 sales (which account for weather normalization, and year-end 2002 customer levels) of about 23.5

million MWh, to obtain its pro forma adjustment to fuel and purchased power expenses of $120.584 million. Thus, while APS' total proforma fuel and purchased power cost (in dollars) is not as high as 2003 power costs would be, the pro forma cost per kWh does reflect the impact of higher loads.

Q. Are the nature of the Company's proforma adjustments appropriate?

A. Both adjustments seem appropriate as a base power cost which would be adjusted by a PPFAC. However, if an adjustor is not adopted, I am concerned that the Company will have essentially proformed one component of its costs to reflect 2003 sales levels, while not all other components were similarly proformed to reflect those sales levels.

Q. What is the effect of using 2003 loads to develop the average fuel and purchased power cost?

A. Load growth tends to increase the Company's fuel and purchased power costs per kWh. To my knowledge APS has not provided an estimate of fuel and purchased power costs based on its lower adjusted 2002 sales, but the effect is substantial. Assuming that sales growth is served with incremental fuel and purchased power at a price of $50/MWh (which is consistent with the forward electricity prices used in the Company's pro forma analysis), the Company's use of the higher sales figure would increase the pro forma average fuel and purchased power cost by approximately $23 million.

APS has not, however, proformed a corresponding decrease in the cost per kWh of its fixed power supply costs. This raises a potential inconsistency, and a potential for APS to overrecover its total power supply costs.

Q. What is your recommendation with respect to APS' use of 2003 sales levels in its derivation of pro forma fuel and purchased power costs per kWh?

A. The Company's use of 2003 sales in this calculation would be reasonable in the context of a PPFAC. Therefore, if the Company is able to develop a PPFAC mechanism that addresses the concerns that I have raised with respect to load growth, its pro forma fuel and purchased power costs would be – subject to the specific adjustments that I recommend below related to gas transportation costs and nuclear unit generation – an appropriate basis.

If the Commission instead determines that a PPFAC is not appropriate at this time, I recommend that the Company's pro forma fuel and purchased power expense be reduced to remove the effects of 2003 sales growth. I estimate that the associated reduction would be approximately $23 million.

IV. PURCHASED POWER AND FUEL ADJUSTMENT MECHANISM

Q. Please summarize your recommendations with regard to a purchased power and fuel adjustment mechanism.

A. Staff recommends that if the Commission decides to approve an adjustor mechanism, the mechanism should include fuel as well as purchased power. However, Staff's primary recommendation is that the Commission should not approve such a mechanism for APS at this time. Below I will explain why Staff recommends against an adjustor that includes only purchased power, and will describe the unique circumstances that result in the recommendation that no adjustor be approved for APS.

Q. Have you reviewed the Commission's findings, in Docket E-01345A-02-0403, with respect to a potential adjustment mechanism to track changes in APS purchased power costs?

A. Yes, I have reviewed ACC Decision No. 66567, and also the October 2, 2003 recommendation of ALJ Farmer. The draft order recommended approval of a Power Supply Adjustor, including fuel and purchased power costs, subject to a number of specific conditions, but the final Order appears to contemplate a mechanism that adjusts APS rates for changes in its purchased power costs, but not fuel costs. A specific methodology for implementing the adjustment mechanism was not adopted.

It is my understanding that in the context of the present docket, the Commission intends to determine whether an adjustor should be implemented for APS and, if so, what the broad features of the adjustor should be.

Q. How would a purchased power adjustor for APS work?

A. In Docket E-01345A-02-0403, the Commission addressed the prospect of a purchased power adjustor conceptually, but did not present all the details of how it would be implemented. For the purpose of this discussion, I will assume a relatively simple purchased power adjustor designed to track changes in the Company's purchased power expenses.

Under this type of mechanism the Company's reference level of purchased power expenses would be established by the Commission, presumably on an annual basis. Retail rates would initially be set to collect this reference level of purchased power expense, along with the other components of the Company's cost of service. The Company's actual purchased power expenses would subsequently be measured, and compared to the reference level periodically, on a cost per kWh basis. To the extent that actual purchased power expenses turned out to be greater (less) than the reference level, the difference would subsequently be collected (returned) by APS over a future period.

The specific design and implementation of a purchased power adjustor (or other forms of adjustors) would entail a number of details, many of which were raised in the adjustor proceeding. These include the accounts that would be included, the amount of information to be monitored and filed, how often the adjustor could change, amortization schedules, the amount that rates would be able to increase because of the adjustor, etc. However, a purchased power adjustor that does not include fuel raises additional issues.

Q. Would a simple adjustor mechanism focusing only on the Company's purchased power costs have important limitations or drawbacks?

A. Yes, the Commission should consider several significant drawbacks that would be associated with an adjustor that focuses only on changes in the Company's purchased power expenses. These drawbacks stem from the fact that APS' present power supply includes not only purchased power, but also substantial amounts of gas-fired generation, and these resources can substitute for one another.

First, a simple adjustor mechanism reflecting only changes in APS purchased power costs would not effectively capture how a number of practical developments would affect APS' **net power supply costs**, including fuel and purchased power. From the Company's standpoint, this type of adjustor may not "make them whole" when prices are rising, and from the customer' standpoint, this adjustor may not pass along all power cost reductions.

Second, under some conditions, a simple adjustor mechanism focusing only on purchased power expenses (a "PPA") would not provide incentives for APS to operate its system in a least-cost manner, and could encourage APS to make power supply choices that actually increase its net power supply costs. Alternative adjustor mechanisms that addressed only purchased power could potentially be developed, but to accurately track APS' net costs they would need to be fairly complex and would require extensive Commission review.

Q. Please explain the first concern, that a purchased power adjustor would not effectively capture changes in APS' net power supply costs.

A. The problem is that purchased power expenses are only one component of APS' net power supply costs. Changes in purchased power expense are often accompanied by offsetting changes to the other components: **fuel consumption and sales for resale**. Two simple examples may be illustrative.

First, consider an instance in which, shortly after the reference level of purchased power expense is established, wholesale power market prices decline significantly (say, from 3.5 cents/kWh to 3 cents/kWh) while prices for fuel at APS' gas-fired generating units are unchanged (at, say, 3.3 cents/kWh). In response to this change, it will tend to be cost-effective for APS to increase purchases from the short-term power market at 3 cents/kWh, while backing down production from its marginal gas-fired units at 3.3 cents/kWh. In this example the PPA would show APS' purchased power expenses greater than the reference level, indicating that APS is undercollecting, even though APS' net power supply costs have declined.

Alternatively, consider an instance in which the Company's Palo Verde nuclear units are actually available to produce significantly more energy than assumed in the development of the reference level of purchased power expense. The additional production of nuclear energy at relatively low fuel cost will reduce APS' net power supply costs. But if APS has purchased its forecasted electricity needs for the year in advance, using forward contracts, the savings to APS would come through reduced dispatch of its higher-cost gas-fired units or additional resales in the short-term electricity market. In this example, APS' actual purchased power expenses would not decrease, because they are locked in through forward purchases. Instead, the additional Palo Verde energy would allow APS to make some unanticipated short-term resales. The related revenues, and the associated overcollection of power supply costs, would not be captured by the PPA.

These examples show that an adjustor designed to reflect only changes in purchased power expenses (and not fuel, or sales for resale) could realistically indicate that APS is undercollecting in instances where APS' net power supply costs have increased only modestly, or actually decreased. Similarly, a PPA may not capture instances in which APS' net costs have legitimately increased. Other practical examples could be developed to illustrate the limitations of an adjustor that focuses only on purchased power expenses. Note that in these examples APS is assumed to pursue the economic course of action in response to changing fuel prices or power market conditions. The concern is simply that the PPA would not accurately depict the changes in APS' net costs.

Q. Please explain the second concern, that an adjustor focusing only on purchased power expenses could provide incentives that encourage APS not to pursue an economic course; i.e. to make power supply choices that increase its net power supply costs.

A. The primary concern derives from the potential economic substitution between purchasing power and generating energy from APS-owned generating units. Because increases in purchased power expenses would be recoverable through the adjustor, while changes in fuel expenses at APS units would not, APS would generally have an incentive to maximize market purchases in lieu of generating energy from its own units, even if the latter were the cheaper option. This substitution dynamic can be significant in the APS power supply, which contains substantial amounts of dispatchable owned resources (particularly the Company's gas-fired steam and combined cycle units, along with Track B purchases from the PWEC units during summer months). APS has the ability to adjust output from these resources in response to changing prices for fuel and power.

Q. Could a simple PPA be modified to address the concerns that you have raised?

A. Possibly, but simple modifications would probably not make a PPA very effective at capturing changes in the Company's net power supply costs. This is because purchased power volumes and prices are each subject to significant variation from month to month and year to year, making simple approximations (e.g., applying observed changes in electricity market prices to the volumes of purchased power assumed in the reference cost analysis) subject to significant errors. In order to capture these net changes accurately, a more detailed analysis (resembling a full adjustor that tracks actual fuel expenses and sales for resale) would be needed.

Q. In view of the foregoing, what is Staff's recommendation with respect to a purchased power adjustor?

A. For the reasons above, and considering APS' particular power supply mix, Staff believes that an adjustor mechanism focusing solely on purchased power expenses is not advisable. The preferable options range from no adjustor mechanism at all (i.e., a fixed retail rate) to a "full" adjustor designed to reconcile all changes in APS' fuel costs, purchased power costs, and resales (i.e., a purchased power and fuel adjustor, or "PPFAC").

Q. May there be some circumstances in which a full adjustor, including fuel and purchased power, is preferable to a fixed rate?

A. Yes, although, there are usually legitimate tradeoffs among these options. In Docket E-01345A-02-0403, Staff identified a number of advantages and disadvantages associated with a PPFAC; these remain valid today. Specifically, Staff identified the following **advantages**:

1. The reporting requirements and forecasts facilitate utility planning and Staff overview of costs;
2. An adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates;
3. Adjustors can create price signals to consumers, although the effectiveness is reduced considerably when a band is included and a twelve month rolling average is used;
4. Adjustors can help reduce the frequency of rate cases;
5. Regulatory lag between the incurrence of an expense and its recovery is reduced, and generational inequities are also reduced.

The **disadvantages** identified by Staff were as follows:

6. Adjustors can reduce incentives to minimize costs.
7. An adjustor that includes fuel or purchased power costs potentially biases capital investment decisions toward those with lower capital costs and higher fuel costs;
8. Adjustors create another layer of regulation, in addition to rate cases;
9. An adjustor can shift a disproportionate portion of the risk of forced outages and systems operations from shareholders to ratepayers;
10. Adjustors result in piecemeal regulation, in that they reflect an increase in one expense but ignore potential offsetting savings in other costs;

11. Adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers;
12. Proper monitoring of adjustor filings and audits require the devotion of significant Staff resources;
13. Under an adjustor rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Q. What other empirical circumstances bear on the advisability of an adjustor mechanism?

A. Empirical considerations which may affect the advisability of an adjustor mechanism include the prospective volatility of fuel and/or purchased power expenses, the proportion of the utility's revenue requirement which is subject to such volatility, and the rate of load growth which can be expected. Utilities with a large proportion of their costs subject to volatility, based on events outside of their control, and with relatively low load growth, are likely to be appropriate candidates for adjustor mechanisms.

In the specific circumstances facing APS, natural gas prices (including spot prices and futures contracts) have exhibited substantial volatility in recent years, and appear likely to continue to do so in the near future. As shown in Exhibit DCS-3, the Company's power supply mix in the near future will rely significantly on energy from natural gas-fired generating units and purchases, and (to a lesser extent) on short term power purchases. Gas costs represent a large fraction of the Company's net fuel and purchased power costs and a significant fraction of its total annual revenue requirement. These costs are not entirely out of APS' control, however, as APS can (and presently does) reduce its exposure to potential market price changes by hedging (e.g., by purchasing fuel well before it is consumed, or utilizing future contracts or options). In the context of considering an adjustor mechanism, it is also important to note that a very substantial portion of the Company's power supply costs are fixed.

Q. Do the empirical circumstances in APS' case raise concerns with a fuel and purchased power adjustor that were not discussed explicitly in the previous proceeding?

A. Yes. Staff is concerned that if APS continues to experience substantial load growth (i.e., growth in retail kWh sales), a PPFAC could lead to overrecovery of total power costs.

Specifically, a large fraction of APS' power costs are fixed costs (e.g., depreciation, return on equity, fixed O&M) associated with its owned generating units. Customers pay for these fixed costs as part of their volumetric rate. The concern is that as sales grow, APS will essentially be collecting more money from retail customers for its fixed power costs, even though such costs do not increase commensurately. The PPFAC, at least in the form proposed by APS and discussed above, would not recognize this. That is, while a PPFAC would compensate APS for observed increases in its fuel and purchased power costs per kWh caused by load growth, it would not reflect offsetting declines in cost per kWh sold associated with the fixed components of power supply costs. This is an example of the "piecemeal regulation" concern cited by Staff in Docket E-01345A-02-0403; its effect is that APS stands to achieve increasing net power cost margins associated with load growth.

Q. In this context, is growth in APS sales a significant issue?

A. Yes, the Company's retail sales increased at an average rate of over 3 percent per year between 1997 and 2002[2], and APS projects growth to continue at an average rate of over 4 percent per year over the next five years.[3]

Q. Have you been able to estimate what impact a PPFAC might have in these circumstances?

A. Yes, Exhibit DCS-5 illustrates how load growth of 4 percent (equivalent to the annual growth forecast by APS) would affect the Company's power supply costs

[2] Supplement to APS 2002 Annual Report

[3] APS 2003 Long Range Forecast (August 2003)

and collections from ratepayers. Key points from this illustration are the following:

- Fuel and purchased power costs represent well under half of APS' total power supply costs.
- Much of the Company's power supply costs are fixed, and are not included in fuel and purchased power. These costs - which include depreciation, return on equity, and income taxes associated with APS owned generating plants - are not driven by sales. The actual fixed costs in APS rates will depend on several factors, including whether the PWEC units are rate based. For the purpose of this illustration I have used a figure of $500 million which is within the range of potential outcomes.
- Assuming that sales growth of 4 percent is supplied with a combination of purchased power and increased generation from APS units, at an average cost of about $50/MWh, APS' actual fuel and purchased power costs per kWh would increase, leading to an undercollection of about $27 million. Under a simple PPFAC, this amount would ultimately be collected from ratepayers in a future period.
- APS' fixed power supply costs are not driven by sales[4] in the near term, and therefore decline on a cents per kWh basis by 4 percent in this example. APS would effectively overcollect for these fixed power supply costs by about $20 million. Under a simple PPFAC mechanism, this overcollection would not be tracked or returned to ratepayers.

This example illustrates that if retail sales increase significantly, a simple adjustor combined with based rates could result in a windfall to APS on the order of $20 million. Undercollections in one portion of power supply costs – fuel and purchased power – would be reconciled through the PPFAC while overcollections in fixed power supply costs would not. Note that APS total power supply costs

[4] In actual practice, some of the fixed power supply costs (e.g., depreciation, return) would tend to remain constant or decrease over time, while others (e.g., power plant O&M) would tend to increase. Because a substantial fraction of APS' fixed power supply costs are of the former type, the results illustrated here are not strongly sensitive to this breakdown and may be conservative.

(including the components that are increasing and decreasing on a cents/kWh basis) track relatively closely to those being collected in rates.

Q. Does the concern about net revenues associated with load growth need to be addressed?

A. Yes. APS has experienced significant load growth during recent years and expects continued robust growth in the future. Further, fixed costs (which would not be included in the PPFAC) make up a large fraction of APS' total power supply costs. Due to these circumstances, Staff believes that the load growth issue is a particular concern in the context of the APS system. Staff believes that the Commission should not adopt an adjustor in this case if the issues associated with load growth cannot be adequately addressed. Staff would, however, be willing to review suggestions from the Company in its rebuttal case as to how to design an adjustor that appropriately addresses these issues.

Q. Given the respective advantages and disadvantages, what is Staff's present recommendation?

A. Considering the context of APS' present power supply, Staff recommends against a PPFAC.

Q. Could a PPFAC potentially be developed that would address the concerns you have presented?

A. Yes. A more complex adjustor could attempt to prevent windfall gains resulting from load growth. For example, the earnings test proposed by Staff in Docket E-01345A-02-0403 would have accomplished this objective. Similarly, in the past Colorado has taken steps (e.g., an earnings test, exclusion of purchased power capacity costs from the PPFAC) to address this problem. However, such steps would likely be fairly complex and more difficult to administer than the mechanisms that have thus far been considered in this proceeding and in Docket E-01345A-02-0403.

Q. Would the concerns that you have presented exist without a PPFAC?

A. Yes, the concerns would still be relevant in the absence of an adjustor. An adjustor would exacerbate the concern, however, because it would pass through to ratepayers the portion of APS power supply costs (fuel and purchased power) that is likely to increase as a result of load growth.

Q. Could other modifications to the PPFAC concept help provide the Company with incentives to "hedge" and to otherwise keep down power costs?

A. Yes, a PPFAC could contain a "deadband" range. Rather than triggering a full reconciliation when a certain amount of over- or under-collection was reached[5], as had been proposed in Docket E-01345A-02-0403, a deadband would define an amount of annual variation from the base that would never be collected.

Q. Please explain more fully what you mean by a "deadband" range, and how it compares to the approach proposed by APS in the recent adjustor proceeding.

A. The Power Supply Adjustor mechanism proposed by APS in Docket E-01345A-02-0403 would track over- and under-collections outside a bandwidth in a Balancing Account, with a maximum threshold of $50 million. APS proposed that if and when the Balancing Account passed the $50 million threshold, a new energy-based charge should be created to amortize the full balance over a one-year period, and the current Balancing Account reset to zero. In an instance when APS' cumulative actual power supply costs exceeded those in the current base power supply charge by more than $50 million, APS would have ultimately recovered the entire difference (along with interest) from customers.

Staff's recommendation is that if a PPFAC is implemented, it should incorporate a deadband range approach, with the following key features:

- Variances of net fuel and purchased power costs (i.e., the difference between APS' actual net costs and those that

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5 The trigger discussed in Docket E-01345A-02-0403 would only delay when the adjustor begins to provide recovery, rather than limiting the amount of the recovery.

APS collected in the base power supply charge) would be calculated once per year, on a regular cycle;

? If the annual variance in net fuel and purchased power costs exceeds the prescribed deadband range, the variance in excess of the deadband would be collected from (returned to) customers over the following year, via an energy-based charge (credit). To the extent that the variance in net fuel and purchased power costs is less than the deadband range, no adjustment would be made for that year.

? Over/under collections of fuel and purchased power costs would not be carried over from one year to the next.

? The base power supply charge would remain constant, at the level established in the present rate case, until modified in a future rate case.

Q. Do you recommend a specific deadband range that would apply in the event that the Commission chooses to implement a PPFAC for APS?

A. The choice of the deadband figure should balance several objectives. First, in order to provide the Company with an incentive to control its costs, the deadband range should be sufficiently large that the Company's actual costs have a substantial probability of actually falling within the range. Too small a deadband range would not accomplish this goal, and would also expose customers to PPFAC adjustments for relatively small changes in fuel and purchased power costs. Second, the deadband range should not be so large that the Company suffers serious financial harm if actual fuel and purchased power costs turn out in the high end of the range.

I believe that a deadband range of plus or minus $20 million would accomplish these objectives. I should note that, however, that this deadband could regularly be exceeded if APS load growth continues and the adjustor is not modified in some fashion to reflect the effect of load growth.

Q. How does the "deadband" approach differ from APS' proposal in Docket E-01345A-02-0403, and from the adjustor contemplated in the Commission's Order in that docket?

A. The primary difference is that under the approach that Staff presents in this case, only net cost changes outside the deadband range would be passed through to customers. Over a significant range of actual net costs, APS would bear the costs and rewards of the fuel and power procurement choices that it makes, giving APS a significant direct incentive to control its net power costs. This feature addresses, to a significant degree, one of the key concerns identified by Staff (and by other parties) that would otherwise be associated with a PPFAC. The annual review process proposed by Staff is intended to reduce the frequency and burden associated with the review of APS' actual power supply costs.

Q. What is your recommendation regarding the conditions approved by the Commission in Decision No. 66567?

A. Staff recommends that an adjustor include Condition 1, which would allow review of the workings of the adjustor after three years. Staff also believes that if an adjustor is implemented, it will be appropriate to adopt the conditions in Decision No. 66567 with the exception of Staff Conditions 6 and 11.

Q. Please discuss how the Company's procurement choices will affect its future net power costs, and the considerations associated with how the Commission will review those choices.

A. As discussed above, natural gas fired generation and short-term power purchases play significant roles in the APS power supply. As a result, APS actual future power costs will sometimes depend significantly on the procurement choices (e.g., when to purchase fuel or power on a forward basis, how much to purchase and for how long) that APS makes. The outcomes of such decisions are likely to attract scrutiny if a PPFAC is implemented, because customers may directly bear those outcomes.

In California and some other U.S. states, a lack of clarity about these parameters has sometimes resulted in disagreements as to whether utilities could have avoided substantial excess power costs, and whether the utilities should be allowed to collect them from retail ratepayers. In particular, in the aftermath of the Western power crisis of 2000-01, some utilities argued that they failed to hedge their market exposure (e.g., by purchasing forecasted needs ahead of time through forward contracts) because there was uncertainty as to how such commitments would be evaluated for retail rate recovery.

APS has indicated that its present practice is to purchase (or otherwise hedge the cost of) a majority of its forecasted fuel and power needs ahead of time. While it is appropriate that APS has a strategy, and some degree of hedging is advisable, I am not aware that APS and the Commission have an understanding as to what the goals of APS' hedging strategy should be.

Particularly if an adjustor mechanism is adopted, it will be useful for Arizona regulators to maintain a dialogue (or at least an understanding of basic principles) with APS regarding the objectives of its procurement and hedging activities and the appropriate tools for it to use. Such a dialogue would help to avoid misunderstandings, and would maximize the likelihood that APS' hedging activities are oriented toward goals that the Commission supports.

In context of the present case, I would recommend that the Commission set some broad ground rules for the design and implementation of APS' procurement strategy. Specifically, I recommend that the Commission consider the following guidelines:

? The presence of a PPFAC does not mean that APS should adopt a strategy of purchasing its fuel and power primarily from the spot market. Rather, APS should continue to judiciously use forward purchases and other types of transactions to reduce the expected cost and/or risk of the portfolio.

? Forward purchases and sales, options, and other derivative transactions should be conducted solely for the purpose of hedging APS' retail book, and should not be used for speculation.

? APS should base its procurement decisions on appropriate risk management tools and analysis, and proper market intelligence, regarding its market exposures and the products available to hedge those exposures.

- APS' transaction strategy and implementation will be subject to after-the-fact review by the Commission. The prudency of APS' procurement choices will be evaluated based on the pertinent information (e.g., market fundamentals, forecasted power requirements, the price of the products available) that was available at the time the choices were made (and on the appropriateness of APS' strategy) rather than on how the transactions "turned out" in hindsight.
- APS should maintain proper records regarding its hedging strategy, the information that it reviewed in evaluating potential transactions for the APS system book, and the rationale for entering into (or choosing not to enter into) specific transactions.

While these guidelines may put some burden on APS, Staff believes that they are ultimately in the interest of both APS and ratepayers because they serve to define expectations and avoid potential costly outcomes of the type that can lead to disallowances.

V. GAS TRANSPORTATION COSTS

Q. Please summarize your concerns regarding APS' estimate of natural gas transportation costs.

A. APS' pro forma analysis of fuel and purchased power costs includes an increase in natural gas transportation costs. The increase is based in part on the assumption that the Company will need to make significant monthly firm purchases of gas transportation service from the capacity release market. As I will explain more fully below, my review indicates that APS' estimate of gas transportation costs is somewhat overstated, in part because it understates the amount of firm transportation that will be available under existing contracts at more favorable prices. To address this issue, I recommend that the Company's pro forma gas transportation costs be reduced by about $4.6 million annually if the PWEC generating units are rate based, and by about $1.5 million if the PWEC assets are not rate based.

Q. Please provide a brief overview of the Company's natural gas purchases.

A. APS and PWEC purchase the vast majority of their natural gas requirements from producers located in the Permian Basin in west Texas and southeast New Mexico; the San Juan Basin in northwest New Mexico and southwest Colorado; and the Waha trading hub. Prior to September of 2003, the gas from these basins was transported by El Paso Natural Gas, a FERC jurisdictional interstate pipeline, under a full requirements (FR) contract jointly held by APS/PWEC. The FR contract contained no limit on the amount of gas that APS/PWEC could purchase, but it was subject to capacity constraints on El Paso's pipeline system including the primary receipt points specified in the contract. To the extent that customer nominations exceeded capacity at a given receipt point, nominations were reduced on a *pro rata* basis.[6] Customers unable to receive all of their nominated firm volumes were allowed to re-nominate service from other receipt points.

In order to reduce the incidence of pro rata allocations and improve the reliability of firm service on El Paso, the FERC in an Order issued July 9, 2003 directed that FR contracts be converted to contract demand (CD) contracts, effective September 1, 2003. CD contracts provide firm customers the right to transport gas up to specified quantity limitations at delivery points designated in the contracts. The primary source of capacity to support these new contract demands is El Paso's unsubscribed system capacity, which was historically being used to supply FR customers.[7] Unsubscribed capacity includes the rights to capacity on El Paso turned back by California local distribution companies. This turned-back capacity was divided into three blocks: Block I capacity has alternate receipt point rights unless the capacity is sold for maximum tariff rates and, in that event, it has

[6] In recent years, gas supplies from San Juan have been less expensive than gas from Permian and Anadarko, making San Juan the preferred gas supply area for El Paso customers. As a result, San Juan nominations have regularly exceeded available capacity resulting in frequent pro rata reductions in nominations. In contrast, nominations for gas supplies from the other basins connected to El Paso (Permian and Anadarko) were rarely reduced.

[7] In this context, unsubscribed capacity means El Paso's total available system capacity less the capacity under contract to CD customers plus a reasonable amount of reserved for small FR customers not subject the FERC's conversion order.

primary receipt point rights only to the Permian and Anadarko Basins. Block II turned back capacity has primary access to all system receipt points including the San Juan Basin, but can be recalled by northern California shippers. Block II capacity also has primary deliveries to Topock in California. Block III capacity has primary access rights to all system receipt points. The FERC also directed El Paso to make additional capacity available to former FR customers through the Line 2000 Power-Up Project ("Power-Up").[8]

Q. How did El Paso allocate the unsubscribed capacity among the converting FR customers?

A. The FERC directed El Paso to apportion the unsubscribed capacity among FR customers using each customer's pro rata share based on its monthly demand over the 12 months ending August 31, 2002. The APS/PWEC share of the allocated capacity comprises four categories: Base, Line 2000, Block and Power-Up. The Base and Line 2000 capacities have primary access to all system receipt points. As noted above, the Block capacity derives from capacity turned-back by California local distribution companies and is divided into three blocks. The vast majority of APS/PWEC's block capacity is associated with Block II. Finally, the Power-Up capacity has receipt point rights only to Permian. Exhibit DCS-6 shows monthly APS/PWEC transportation capacities on El Paso, including the firm and non-firm designations that APS has assumed in its pro forma analysis. As shown on the exhibit, the total CD capacity allocated to APS/PWEC varies monthly from a minimum of 98,000 MMBtu/day in February to a maximum of 385,000 MMBtu/day in August.

Q. Please summarize the Company's calculation of gas transportation costs for the adjusted test year.

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[8] Rates on El Paso were established pursuant to a Settlement entered into in 1996. The 1996 Settlement set the current rates and terms and conditions of service for a ten-year period, i.e., until January 1, 2006. Service under the new CD contracts will be charged at rates established in the 1996 Settlement.

A. The Company has assumed that a portion of the daily gas requirements for the APS/PWEC gas-fired generating units will be met with the allocated Base and Line 2000 CD entitlements from the FERC RP00-336 proceeding.[9] As shown in the "Firm Capacity" portion of Exhibit DCS-6, these entitlements vary monthly from a low of 53,000 MMBtu/day in February to a high of 172,000 MMBtu/day in August. To put these entitlements in context, the minimum and maximum daily gas requirements for the APS/PWEC units for February 2003 were estimated at approximately 51,000 and 226,000 MMBtu/day respectively. For August 2003, the corresponding quantities were 123,000 and 303,000 MMBtu/day.

Daily gas requirements in excess of the Base and Line 2000 entitlements are assumed to be met with firm purchases of pipeline capacity in El Paso's capacity release market, rather than with the Block and Power-Up CD entitlements allocated to APS/PWEC in Docket RP00-336. Capacity release is a FERC approved program that allows shippers of gas on El Paso to sell or purchase surplus capacity at market based rates. The Company's calculation assumes that APS/PWEC will purchase at the beginning of each month sufficient firm release capacity to meet the projected maximum daily requirement for the month at a rate of almost twice that paid for firm Base and Line 2000 CD service.[10]

On days when the sum of the Base and Line 2000 CD entitlements and the capacity release purchases exceed the projected daily gas requirements, the Company's calculation assumes that the excess will be released on a daily basis at a rate equal to one fourth of the price to acquire that capacity.[11] Based on the projected daily gas requirements for the APS and PWEC gas fired generating units in the adjusted test year, the assumed capacity release purchases and sales, and the assumed charges for CD and capacity release transportation services, the

[9] The Line 2000 capacity is an allocation of recently completed capacity. Base capacity is unsubscribed system capacity.
[10] The basis for this rate is Sheet 23 of the El Paso Tariff. That is, the Company assumes it will pay a blend of the maximum daily base reservation rates for transportation from the San Juan and Permian basins to Arizona.
[11] Although the Company was unable to provide support for this assumption, it contends that it is reasonable because daily releases of capacity are less valuable than monthly releases.

Company estimated a net transportation cost of $20.5 million. This calculation is summarized in Exhibit DCS-7.[12]

Q. Why did the Company not utilize in its calculation of pro forma transportation costs the Block and Power-Up CD capacity allocated to APS/PWEC in RP00-336?

A. The Company contends that the Block and Power-Up capacity allocated to APS/PWEC in RP00-336 is less firm than the Base and Lone 2000 capacity.[13] In comments filed with the FERC in Docket RP00-336, APS/PWEC argued that: (i) Block II capacity is recallable by California customers; and (ii) the primary delivery points associated with the Block capacity are not usable because they are located in California, thus requiring the Company to re-nominate to secondary delivery points in its market area. Since secondary delivery points would be scheduled at a lower priority than primary points, the risk of curtailment would be increased.[14] In addition, APS/PWEC has argued that there is insufficient pipeline capacity connecting El Paso's northern and southern systems to ensure that gas delivered to Topock will be delivered to the Arizona market area. A map depicting the major features of the El Paso pipeline system is shown in Exhibit DCS-8.

Q. Do you agree with these arguments?

A. First, it is true that California customers may recall Block II capacity. To do this, they must at least match the rate in the contract covering the capacity to be recalled and subscribe to the capacity for a term of longer than one month. If a customer seeks to recall the capacity for a term of less than one month, it must

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[12] Note that I attempted to replicate the Company's calculation, but fell short by approximately $0.5 million. Our request for the workpapers supporting the Company's estimate is currently outstanding.

[13] See response to LCA 19-461, which is attached as Exhibit DCS-6.

[14] See Joint Answer of Arizona Public Service Company and Pinnacle West Energy Corporation to Request of El Paso Natural Gas Company for Clarification or Rehearing, Docket RP00-336, September 16, 2003.

agree to pay the maximum rate.[15] These recall conditions may limit the likelihood that recalls will be frequent.

There is almost no operating history under the new CD regime (which was implemented in September 2003) that would provide a basis for estimating with confidence how often Block II capacity will be recalled, whether recalls will be limited to peak periods, or how much of the Block II capacity might actually be recalled. Despite this lack of operating history, it seems reasonable to assume that if Block II capacity is recalled, it is more likely to occur in the on-peak months. Similarly, there is little market history upon which to base the likely availability and price of release capacity during periods when Block II capacity might be recalled. This is significant because if California customers were to recall Block II capacity for economic reasons (i.e., because it provides them access to gas priced below that available on other pipelines), APS/PWEC might be able to replace the recalled capacity with purchases in the release market at a limited incremental cost.

Regarding the second claim, the Company itself notes in comments filed in Docket RP00-336 that the FERC has already accepted its argument and directed El Paso to modify the transportation service agreements to incorporate primary delivery points located in its historic market area.[16]

Regarding the third claim, the Company itself has argued that the existing allocations of the north-to-south crossover capacity are based on customer delivery point preferences provided to El Paso in December 2002, long before the FERC clarified that APS/PWEC and other FR customers could re-designate delivery points on their Block capacity. Consistent with this argument, the Company has requested the FERC to direct El Paso to re-allocate the north-to-south capacity using allocation factors that reflect re-designated delivery points. While such a re-allocation would not guarantee APS/PWEC full use of the San

[15] FERC Order on Rehearing, July 9, 2003, Docket RP00-336, page 71

[16] See Joint Reply Comments of Arizona Public Service Company and Pinnacle West Energy Corporation to Technical Conference and Associated Filings, page 1, November 3, 2003 in RP00-336

Juan receipt points associated with its Block II capacity entitlements, it would clearly enhance the reliability of that capacity.

For the above reasons, I believe the reliability of Block II capacity is likely to be greater than that assumed by the Company in its calculation of transportation costs.

Q. Are there other points that you would like to make regarding the issue of gas supply reliability?

A. Yes, there are at least two additional points that I believe are relevant. The first relates to the Power-Up capacity allocated to APS/PWEC in RP00-336, which accounts for 41 percent of the total capacity that the Company classified as non-firm in its pro forma analysis. Since the Power-Up project makes new capacity available through the addition of compression to the Line 2000 project, and its primary receipt points are located in the Permian basin, this capacity will not be subject to the constraints that could limit the reliability of Block II capacity. Also, as I noted earlier, the Power-Up capacity is not subject to recalls by California shippers, as is Block II. Thus, it would appear that at least 41 percent of the capacity that APS has designated as non-firm in its pro forma analysis could be reasonably relied upon to displace more costly capacity release purchases.

My second point relates to the fact that in developing its pro forma gas transportation costs, APS assumed that it will need to purchase sufficient firm monthly transportation to meet the simulated gas requirements for the single highest day of usage in each month. These fuel requirements include generation to serve APS' own load requirements, as well as sales for resale on a daily or hourly basis. APS would only conduct such sales, and would only purchase firm transportation to support them, if it is cost-effective to do so. It is not clear that APS would purchase firm monthly transportation to support spot market energy sales (which typically feature limited profit margins), as the Company's pro forma analysis effectively assumes. It is reasonable to expect that APS will weigh the costs and risks associated with potential transaction strategies, choosing a strategy that seeks to limit expenses while maintaining a reliable fuel supply. This process is likely to yield a less costly outcome than that assumed in the pro forma analysis.

Q. Given the foregoing, what is your recommendation with respect to gas transportation costs?

A. Some judgment is required here. On one hand, there are a number of uncertainties associated with the transition from the historical FR contract regime to a CD regime. As explained above, the Company's pro forma estimate of gas transportation costs is based on a number of significant assumptions (e.g., market prices for monthly capacity release purchases and daily capacity release sales, how often certain transportation rights will be recalled, APS' own procurement strategy under the new CD regime) that cannot be tested against any significant operating history. In fact, it is possible that the appellate court could choose to remand the case back to FERC for further action, raising uncertainty about the ultimate allocations and other details of the CD regime.

On the other hand, it does appear that a transition to a CD regime is in progress, and that this will increase costs to APS by some amount. I understand that on September 1, 2003, El Paso actually terminated FR transportation service to APS/PWEC and replaced it with CD service in a manner consistent with the FERC orders in RP00-336. My recommendation therefore reflects the new CD regime using the Company's general approach and assumptions, but adjusted to reflect the specific concerns raised above regarding the amount of additional firm transportation that APS will need to purchase.

Specifically, I believe that it is reasonable to assume that 75 percent of APS/PWEC's entitlement to Block and Power-Up capacity can be utilized to deliver gas to APS/PWEC generating units in all months, at a reservation rate of \$0.1636/MMBtu/day.[17] This approach is equivalent to assuming full availability of the Power-Up project in all months and a substantial rate of recall for the Block allocations in certain high demand months. I assume that the balance of APS' transportation needs will be purchased from the capacity release market on a monthly basis, using the Company's approach and price assumptions. Using this method, I estimate a total net transportation cost of about $15.9 million per year, a reduction of $4.6 million from the Company's pro forma analysis. Exhibit DCS-10 summarizes this calculation.

Q. Did the Company also estimate the net transportation cost under a scenario in which PWEC units are not rate based?

A. Yes. APS estimates that the net cost of transporting gas on the El Paso pipeline to meet its daily gas requirements (including those associated with the Track B purchases) in the adjusted test year at $11.98 million. As with the PWEC rate base scenario, the Company's calculation assumes that all of the Base and Line 2000 capacity allocated to APS/PWEC in FERC proceeding RP00-336 will be available to meet APS' gas requirements. Similarly, daily gas requirements in excess of the Base and Line 2000 entitlements are assumed to be met with firm capacity purchases in the capacity release market.

Q. Do you agree with the Company's estimate?

A. No. For the reasons given above regarding the Company's calculation under the PWEC rate base scenario, I believe that the APS analysis overstates the amount of capacity release purchases that it will need to make. Assuming that APS will retain 100% of the APS/PWEC CD entitlements, and that 75 percent of the Block and Power-Up capacity can be treated as firm, I estimate an adjusted test year transportation cost of approximately $10.5 million, or $1.48 million less than the cost estimated by the Company. This calculation is summarized in Exhibit DCS-11.

VI. NUCLEAR UNIT AVAILABILITY

[17] See LCA 19-469, which is attached as Exhibit DCS-9

Q. Please explain how the operation of the Palo Verde nuclear units can impact APS' adjusted test year fuel and purchased power expense.

A. The Palo Verde nuclear units, in which APS has a 29% ownership interest, are the largest and lowest-cost generating units on the APS system. Thus, any increase in the availability of these units could avoid the need to burn expensive fuel in generating units with higher variable costs or, alternatively, avoid purchases of relatively high-priced wholesale power.

Q. What assumptions did the Company make regarding operation of the Palo Verde nuclear plant in the adjusted test year?

A. The Company used different capacity factors for the three units in its modeling of system fuel and purchased power costs.[18] Unit 1 was assumed to have an annual average capacity factor of 97.6% during the adjusted test year, reflecting no planned outages for refueling and limited unscheduled outages. Units 2 and 3 were assumed to have capacity factors of 86.8% and 87.7% respectively, reflecting planned refueling outages of over 30 days for each unit. Overall, the plant was assumed to have a weighted average capacity factor of 90.6%.

Q. Do you agree with these assumptions?

A. Not totally. While it is reasonable to assume that refueling outages at multi-unit nuclear plants will be staggered, thus resulting in each unit having a different capacity factor in any given year, those capacity factors should not be the basis of fuel and purchased power cost estimates in base rate proceedings. The Palo Verde nuclear units, like other pressurized water reactors, operate on a three year fuel cycle.[19] Thus, in order to avoid using a capacity factor that is not representative of future operations, I recommend using a three-year rolling average capacity factor to estimate the output of each unit. Using actual annual capacity factors for the Palo Verde units over the last three years results in a decrease in Unit 1 output and increases in the output of Units 2 and 3 relative to

[18] Capacity factor is a measurement of the plants' actual operation, compared to its rated capability.
[19] This means that each unit will be refueled in two of any three consecutive years.

the output levels assumed in the Company's pro forma analysis.[20] These historical unit operating levels are equivalent to weighted average capacity factor of 91.8%, which is just over 1% more than the Company's assumption.

Q. How do your capacity factor assumptions compare to industry averages?

A Data on US nuclear industry capacity factors is reported by the Nuclear Energy Institute. Those data show that most nuclear plant operators have been successful over the last decade in minimizing the frequency and duration of forced outages and minimizing the duration of scheduled outages. As a result, the industry average capacity factor has improved dramatically from just 71.3% in 1992 to 91.9% in 2002. The industry average does not, of course, show the variation in performance between plant operators. This is provided in Exhibit DCS-12, which presents industry capacity factor data by quartile. This exhibit shows that the top 25% of performers (i.e., 1st Quartile) had an average capacity factor of 96.5% in 2002, whereas the 4th Quartile averaged only 85.8% in the same year. Based on this analysis, the Palo Verde nuclear units would appear to rate as 2nd and 3rd Quartile performers. It is also significant that the weighted average capacity factor for Palo Verde that results from using the three-year rolling averages (91.8%) is less than the plant's weighted average capacity factor of 94.4% in 2002, the test year for this case. My recommendation represents a reduction in the Palo Verde production (and an associated increase in APS net power supply costs) relative to the test year actual results.

Q. What is the basis of the capacity factors used by the Company in its pro forma analysis?

A Despite requests for supporting workpapers and calculations, the Company did not clearly explain how it developed the capacity factors underlying the Palo Verde monthly generation quantities in its pro forma analyses.

[20] The three-year rolling averages for Units 1, 2 and 3 are respectively 92.5%, 90.7% and 92.1%. The corresponding factors in the Company's analysis are 97.6%, 86.8% and 87.7%.

Q. What are the cost implications of your recommended capacity factors?

A Based on the assumption that an increase in nuclear generation will displace wholesale market power purchases, I estimate that this would reduce APS' purchased power expense by approximately $5 million in the adjusted test year. This calculation is summarized in Exhibit DCS-13.

Q. Does this conclude your testimony?

A. Yes.